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The cost of transmission for wind energy in the United States: A review of transmission planning studies

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ABSTRACT

Rapid development of wind capacity in the United States has been coupled with a concern that increasing wind capacity will require substantial transmission infrastructure. This report summarizes the implied transmission cost per kW of wind from a sample of 40 transmission studies. This sample of studies, completed from 2001 to 2008, covers a broad geographic area across the U.S. The primary goal in the review is to develop a better understanding of the transmission costs needed to access increasing quantities of wind generation. A secondary goal is to gain a better appreciation of the differences in transmission planning approaches, in order to identify those methodologies that seem most able to estimate the incremental transmission costs associated with wind development. The total range in transmission costs per kW of wind implicit in the study sample is vast – ranging from $0/kW to over $1500/kW. The median cost of transmission from all scenarios in the sample is $300/kW, roughly 15–20% of the cost of building a wind project. The median cost of transmission is near the upper end of the range implied by two higher-level assessments of transmission required to provide 20% wind electricity in the U.S. by 2030.

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1. Introduction

Wind power capacity additions are growing at a rapid pace in the United States (see, e.g., [1]). These additions are driven by federal tax incentives, state-level renewables portfolio standards, the rising cost of fossil-fuel generation, concerns about energy security and price volatility, and growing interest in reducing carbon dioxide emissions.

This rapid development, however, has been coupled with a growing concern that maintaining or increasing wind capacity additions will require substantial additions to the nation's transmission infrastructure (see, e.g., [2–5]).[1] A variety of barriers exist to new transmission development, and many studies have expressed concern that transmission investments in the United States are not keeping up with the need for those investments [2,8–13].

Transmission is particularly important for wind power due to the unique characteristics of the wind resource and wind power projects [14,15]. Specifically, wind energy depends on wind resources that are sometimes located far from load centers, and wind development is therefore expected to increasingly rely on access to the bulk transmission system in order to move power from resource areas to load centers [3,16]. Moreover, the total developable wind resource in an area to be served by new transmission is almost always larger that the size of an individual wind power project. As such, economies of scale in transmission investments dictate that it is more efficient to proactively build larger transmission ahead of wind generation rather than make smaller transmission investments for individual projects [17–19]. Additionally, individual wind projects can be developed in a relatively short time period of two to three years, whereas large transmission facilities can take a decade to plan, permit, and construct. Finally, wind power projects rely on a variable resource and typically operate at capacity factors that range from 30% to over 40%, ensuring that any transmission dedicated solely to wind generation will not be fully utilized for large portions of the year.

Various initiatives are underway to address the barriers that new transmission investment poses to renewable energy development specifically, and to address constraints to transmission expansion more broadly. The Federal Energy Regulatory Commission (FERC), for example, is currently working with transmission operators and stakeholders to reform the process for generators to interconnect with the bulk transmission system and to require proactive participation in regional transmission planning processes for economic transmission development [20,21]. In addition, under authority granted by the Energy Policy Act of 2005, the U.S. Department of Energy now has the ability to designate transmission constrained areas and FERC – under certain circumstances – has the ability to support transmission investment in those areas. More generally, a growing number of state and regional entities are establishing policies and processes to proactively tackle the transmission barrier for renewable energy, through designation of renewable energy zones, creation of transmission infrastructure authorities, and other means [1,22].

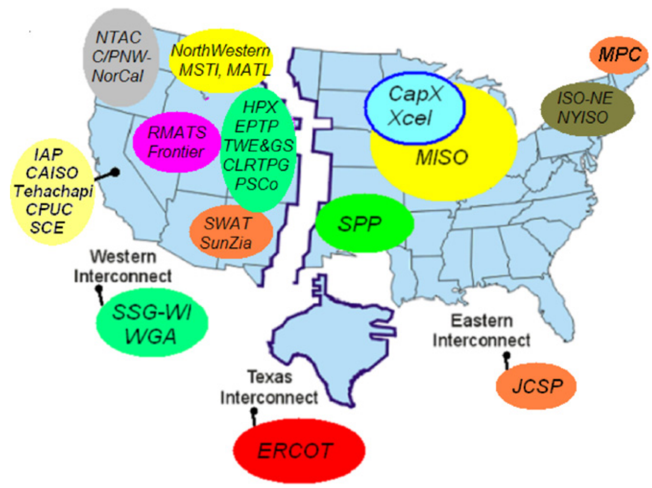


Fig. 1. General geographic location of transmission studies in sample.

Though it is clear that institutional issues related to transmission planning, siting, and cost allocation will pose major obstacles to accelerated wind power deployment, also of concern is the potential cost of this infrastructure build out. Though it may be general knowledge that new transmission will be required for accelerated development of wind energy and that the initiatives noted above will reduce impediments to that transmission development, there is lesser understanding of how much that transmission will cost. Consequently, there is also little consensus on whether or not the cost of developing transmission will be a major barrier to the continued development of wind energy, or whether the institutional barriers to transmission expansion are likely to be of more immediate concern.[2]

Broadly, there are two ways to estimate the cost of transmission for wind power: top-down and bottom-up. A top-down approach is used in high-level studies like those that rely on the Energy Information Administration's (EIA) National Energy Modeling System (NEMS) and those that use the National Renewable Energy Laboratory's (NREL) Wind Deployment System (WinDS) model. Conceptual analyses are also sometimes included in more-academic studies of the feasibility of long-distance transmission for wind (see, e.g., [23–25]). Though there are numerous advantages to these approaches, they do not incorporate detailed physical modeling of the transmission system, and therefore generate only coarse approximations for the transmission costs associated with increased wind power development. Alternatively,

[1] Concern about the transmission needs associated with higher levels of wind penetration are not limited to the U.S. In fact, in addition to more-incremental transmission upgrades, very long-distance transmission solutions have been discussed in both Europe [6] and China [7].

[2] Our focus on the cost of transmission for wind energy does not address the issue of the *allocation* of transmission costs to particular wind projects. The allocation of costs may also be a barrier to continued development of wind energy but we group the allocation of costs into the institutional barriers and do not address the issue further in this article.

Table 1
Description of studies evaluated in analysis.

Region	Principal author	Date	Title of study	Abbreviation	Scenario description
California	California ISO (CAISO)	August 2008	Report on Preliminary Renewable Transmission Plans	CAISO-A1	New 500 kV substation into Southwest Powerlink Line
				CAISO-A2	Expand Midpoint Substation and construct third Midpoint-Devers and new Devers – Mira Loma (or Valley) 500 kV line
				CAISO-A4	Central California Clean Energy Transmission Project (C3ETP) connection of renewable resources in the Kern County area
				CAISO-A6	Construct a new 500 kV location constrained resource interconnection facility (LCRIF) to Kramer Jct. and Lugo Substation
	Intermittency Analysis Project	July 2007	Intermittency Analysis Project: Final Report		
	IAP-2010T	2010 20% RPS target with 3 GW of new wind at Tehachapi			
				IAP-2020	2020 33% RPS target
	California ISO (CAISO)	December 2006	CAISO South Regional Transmission Plan for 2006: Tehachapi Transmission Project	Tehachapi	4.4 GW of new generation at Tehachapi Region
	Southern California Edison (SCE)	September 2007	SCE Conceptual Transmission Requirements and Costs for Integrating Renewable Resources	SCE-LA/Kern	Los Angeles and Kern Counties (including Tehachapi)
				SCE-ISM-P	Inyo, San Bernardino, and Mono Counties, Pisgah
				SCE-ISM-EDM	Inyo, San Bernardino, and Mono Counties, El Dorado/Mohave
				SCE-ISM-MP	Inyo, San Bernardino, and Mono Counties, Mountain Pass
				SCE-ISM-V	Inyo, San Bernardino, and Mono Counties, Victorville
				SCE-ISM-K	Inyo, San Bernardino, and Mono Counties, Kramer
				SCE-ISM-I	Inyo, San Bernardino, and Mono Counties, Inyokern
				SCE-IR	Imperial and Riverside Counties, Clusters 9 and 10
	California Public Utility Commission (CPUC) Energy Division	December 2003	Electric Transmission Plan for Renewable Resources in California	CPUC-2017	20% renewables by 2017 as in original SB 1078 schedule
				CPUC-2010	20% renewables by 2010 as proposed in Accelerated Energy Action Plan
Eastern Interconnection	Midwest ISO	December 2008	Joint System Coordianted Plan (JCSP): Economic Assessment, Wrap-up Stakeholder Meeting	JCSP	20% Wind Energy Scenario
Midwest	CRA International	September 2008	First Two Loops of SPP EHV Overlay Transmission Expansion	SPP-CRA	First two loops of SPP EHV Overlay including Prarie Wind and Tall Grass transmission projects (high cost estimate)

Table 1 (*Continued*)

Region	Principal author	Date	Title of study	Abbreviation	Scenario description
	Southwest Power Pool (SPP)	March 2008	Oklahoma Electric Power Transmission Task Force (OEPTTF) Study	SPP-OK-2010N SPP-OK-2020N SPP-OK-2010H SPP-OK-2020H	2010 Nominal Wind 2020 Nominal Wind 2010 High Wind 2020 High Wind
	Quanta Technology, LLC	March 2008	Southwest Power Pool (SPP) Updated EHV Overlay Study	SPP-EHV	Midpoint Design 2: 765 kV EHV Overlay with Ozarks
	Midwest ISO (MISO)	February 2007	Midwest ISO Transmission Expansion Plan (MTEP) 2006: Vision Exploratory Study (Section 7.4)	MISO'06	765 kV Network Overlay from Dakotas to Eastern Seaboard
	CapX Utilities	January 2007	Community Based Energy Development Transmission Study: West Central (MN) Transmission Planning Zone	CapX-CBED	Transmission needs in Central West Minnesota for Community Energy Projects
	Xcel Energy	June 2005	Buffalo Ridge Incremental Generation Outlet Electric Transmission Study	Xcel-BRIGO	Option 31A is the preferred plan for additional generation capacity at Buffalo Ridge
	CapX Utilities	May 2005	CapX 2020 Technical Update	CapX-1 CapX-2	Minnesota-bias Generation Scenario North/West bias Generation Scenario
	Southwest Power Pool (SPP)	May 2005	Kansas/Panhandle Sub-Regional Transmission Study	SPP-X	X-Plan or Plan A
	Midwest ISO (MISO)	June 2003	MISO MTEP 2003	MISO'03-1	Iowa and S. Minnesota 345 kV and Dakotas 500 kV
				MISO'03-2	Northwest 345 kV Expansion and Dakotas 500 kV
	Xcel Energy Xcel-BR-Proj	December 2001 Option 1 to obtain 825 MW of transmission capacity from Buffalo Ridge – Projected	Application for Certificates of Need for Transmission Lines to Support the Development of Wind Powered Generation in Southwestern Minnesota	Xcel-BR-Actual	Actual Transmission Cost in 2008 (SEC 2008)
Northeast	Maine Public Service and Central Maine Power Company	July 2008	Request for Certificate of Public Convenience and Necessity to Construct the Maine Power Connection ("MPC") to Enable Interconnection of Aroostook Wind Energy Project.	MPC	Proposed Route from Northern to Southern Maine
	ISO New England (ISO-NE)	August 2007	New England Electricity Scenario Analysis: Exploring the economic, reliability, and environmental impacts of various resource outcomes for meeting the region's future electricity needs		
	ISO-NE-High	Renewables scenario, high transmission cost estimate		ISO-NE-Low	Renewables scenario, low transmission cost estimate
	GE Power Systems Energy Consulting	February 2004	The Effects of Integrating Wind Power on Transmission System Planning, Reliability, and Operations: Report on Phase 1	NYISO	Incremental wind additions that are possible without new transmission
Texas	Electric Reliability Council of Texas (ERCOT)	April 2008	Competitive Renewable Energy Zones Transmission Optimization Study	ERCOT-TOS-1A	5.2 GW of new wind in 5 CREZs – least cost but less expandable
				ERCOT-TOS-1B	5.2 GW of new wind in 5 CREZs – easily expandable to Scenario 2
				ERCOT-TOS-2	11.6 GW of new wind in 5 CREZs – scenario 2 selected for development by PUCT

				ERCOT-TOS-3	18.0 GW of new wind in 5 CREZs
				ERCOT-TOS-4	17.5 GW of new wind in 4 CREZs (none in Panhandle B)
	Southwest Power Pool (SPP)	April 2007	SPP Transmission Expansion Supplement to Support Development of Texas Panhandle Competitive Renewable Energy Zones	SPP-2	4.5 GW of new wind from Texas CREZ
	Southwest Power Pool (SPP)	December 2006	Southwest Power Pool he's Analysis of Transmission Alternatives for Competitive Renewable Energy Zones in Texas	SPP-1	1.5 GW of new wind from Texas CREZ
	Electric Reliability Council of Texas (ERCOT)	December 2006	Analysis of Transmission Alternatives for CREZs in Texas	ERCOT-C3	3 GW of new wind in the Coast region
				ERCOT-CW3	3.8 GW of new wind in the Central Western Texas region
				ERCOT-M2	3.8 GW of new wind in the McCamey region
				ERCOT-P4	4.6 GW of new wind in the Panhandle region
				ERCOT-Cb1	3.3 GW of new wind in the Central and McCamey regions
				ERCOT-Cb2	4 GW of new wind in the Central and McCamey regions
				ERCOTCb3	5.3 GW of new wind in the Central, McCamey, and Coast regions
West	HPX Participants	June 2008	High Plains Express Transmission Project: Feasibility Study Report	HPX	Renewables only (wind with 10% overbuild and 500 MW of solar)
	K. R. Saline 8-Assoc. (for WestConnect)	January 2008	Western-RMR Transmission Plan 2008–2017: Eastern Plains Transmission Project in 2007 WestConnect Transmission Plan	EPTP-2	Holcomb Station to Green Valley Station
	K. R. Saline & Assoc. (for WestConnect)	January 2008	SunZia Transmission Plan 2008–2017 in 2007 WestConnect Transmission Plan	SunZia	500 kV line from New Mexico to Arizona
	SWAT Renewable Energy Task Force	January 2008	Southwest Area Transmission (SWAT) Oversight Committee-Arizona Renewable Transmission Task Force	SWAT	Arizona
	Northwestern Energy Electric Transmission Planning	January 2008	Mountain States Transmission Intertie (MSTI) Phase 1 Comprehensive Progress Report (Draft) and Open Season Update Meeting	MSTI	500 kV Midpoint to Townsend line

Table 1 (*Continued*)

Region	Principal author	Date	Title of study	Abbreviation	Scenario description
	Arizona Public Service, PacifiCorp, National Grid, Wyoming Infrastructure Authority	January 2008	TransWest Express and Gateway South Stakeholder Presentation January 23, 2008	TWE and GS	Reference Case
	Technical Analysis Committee (PG&E Chair)	November 2007	WECC Regional Planning Review Canada/Pacific Northwest – Northern California Transmission Line Project	C/PNW-NorCal	Hybrid AC in the Northwest and DC to N. California with high renewables (Case A)
	Western Regional Transmission Expansion Partnership (WRTEP)	April 2007	Western Regional Transmission Expansion Partnership: Benefit-Cost Analysis of Frontier Line Possibilities	Frontier-A	3.6 GW of new wind with transmission alternative 7b (500 kV AC line from WY to So. CA)
				Frontier-B	2.6 GW of new wind and 1 GW of coal with transmission alternative 7b
	Montana Alberta Tie Ltd. (MATL)	August 2006	Montana-Alberta Tie 230 kV Transmission Line: Transmission Development Facilities Application Volume One	MATL	New 230 kV line between Montana and Alberta
	Colorado Long Range Transmission Planning Group (CLRTPG)	July 2006	Colorado Long Range Transmission Planning Study 2005–2015	CLRTPG-N1	Northern Resource Scenario – Alternative 1
	Northwest Transmission Assessment Committee (NTAC)	May 2006	Canada-Northwest-California Transmission Options Study	NTAC-1	Submarine DC Cable: Prince Rupert to San Francisco
				NTAC-2A′	AC lines from Vancouver Island to WA/OR border
				NTAC-2A	AC lines from Vancouver Island to Northern California
				NTAC-2B	AC lines from Vancouver Island to Northern California with submarine DC from WA/OR border to San Francisco
	Xcel Energy Transmission Planning	April 2006	Wind Integration Study Report of Existing and Potential 2003 Least Cost Resource Plan Wind Generation	PSCo	Transmission impact of 775 MW of new wind in Colorado
	Tri-state Generation and Transmission and Western Area Power Administration	March 2006	Preliminary Report: Eastern Plains Transmission Project 500 kV and 345 kV Comparison	EPTP-1	South Cases 500 kV Scenario 1800 MW
	Clean and Diversified Energy Advisory Committee (CDEAC) Transmission Task Force	March 2006	Report of the Transmission Task Force to the Western Governors Association (WGA)	CDEAC	High Renewables Case
	Northwestern Energy Electric Transmission Planning	May 2005	Montana-Idaho Path Open Season Study Report	Northwestern	System improvements to move 700 MW from Eastern area, 800 MWfrom Great Falls area, and a total of 1500 MW moved to Idaho
	RMATS	September 2004	Rocky Mountain Area Transmission Study (RMATS)	RMATS-1	Regional 345 kV expansion with 3 GW of new wind
				RMATS-2	Regional 345 kV expansion and long 500 kV lines from WY to CA with 5 GW of new wind
	Seams Steering Group of the Western Interconnect (SSG-WI)	October 2003	Framework for Expansion of the Western Interconnection Transmission System	SSG-WI	High renewables case for 2013

Table 2
Summary of new generation capacity and cost in each transmission planning study (*note*: total transmission cost is reported in nominal dollars from various years).

Region	Principal author	Study abbreviation	Incremental Wind Analyzed (GW)	Total incremental generation analyzed (GW)	Total transmission cost ($ Billion)	Length of new transmission (mi)	Primary voltage of new transmission lines (AC unless noted)
California	California ISO (CAISO)	CAISO-A1	1.1	1.1	$0.30	Not applicable	500 kV
		CAISO-A2	0.5	2.9	$1.50	180	500 kV
		CAISO-A4	1.3	1.3	$1.60	–	500 kV
		CAISO-A6	1.2	1.2	$0.65	–	500 kV
	Intermittency Analysis Project Team	IAP-2010T	5.4	10.9	$1.36	300	500 and 230 kV
		IAP-2020	10.6	26.1	$6.36	1470	500 and 230 kV
	California ISO (CAISO)	Tehachapi	3.6	4.3	$1.80	249	500 kV initially operated at 230 kV
	Southern California Edison (SCE)	SCE-LA/Kern	5.4	7.7	$2.61	352	500 and 230 kV
		SCE-ISM-P	0.6	6.5	$1.55	195	500 kV
		SCE-ISM-EDM	1.9	4.9	$1.90	235	500 kV
		SCE-ISM-MP	0.1	1.2	$0.11	52	230 kV
		SCE-ISM –V	0.3	0.3	$0.07	11	230 kV
		SCE-ISM-K	0.9	4.7	$0.75	–	500 and 230 kV
		SCE-ISM-I	0.8	0.8	$0.25	–	230 kV
		SCE-IR	2.6	8.8	$2.67	300	500 and 230 kV
	California Public Utility Commission (CPUC) Energy Division						
	CPUC-2017	6.4	8.0	$1.80	1500	500 and 230 kV	
		CPUC-2010	6.4	8.0	$1.91	1926	500 and 230 kV
Eastern Interconnection	Midwest ISO	JCSP	236.0	403.1	$78.58	14,937	765 kV and 800 kV HVDC
Midwest	CRA International	SPP-CRA	14.0	18.5	$3.40	1200	765 kV
	Southwest Power Pool (SPP)	SPP-OK-2010N	3.5	3.5	$2.08	–	345 kV
		SPP-OK-2020N	7.0	7.0	$3.17	–	345 kV
		SPP-OK-2010H	4.5	4.5	$2.50	–	345 kV
		SPP-OK-2020H	11.0	11.0	$4.54	–	345 kV
	Quanta Technology, LLC	SPP-EHV	20.7	23.0	$7.89	4073	765, 500, and 345 kV
	Midwest ISO (MISO)	MISO'06	16.0	16.0	$31.00	5725	765 kV
	CapX Utilities	CapX-CBED	3.5	3.5	$0.38	799	345 kV, 230 kV, and 115 kV
	Xcel Energy	Xcel-BRIGO	0.5	0.5	$0.03	101	115 kV
	CapX Utilities	CapX-1	2.3	6.3	$1.41	1885	345 kV
		CapX-2	2.3	6.3	$1.51	2007	345 kV
	Southwest Power Pool (SPP)	SPP-X	2.5	3.1	$0.46	834	345 kV
	Midwest ISO (MISO)	MISO'03-1	10.0	48.3	$0.66	1053	500 and 345 kV
		MISO'03-2	10.0	48.3	$1.89	2420	500 and 345 kV
	Xcel Energy	Xcel-BR-Proj	0.8	0.8	$0.16	384	345 and 115 kV
		Xcel-BR-Actual	0.8	0.8	$0.23	–	345 and 115 kV
Northeast	Maine Public Service and Central Maine Power Company	MPC	0.8	0.8	$0.63	199	345 kV
	ISO New England (ISO-NE)	ISO-NE-High	6.8	6.8	$3.90	–	–
		ISO-NE-Low	6.8	6.8	$0.58	–	–
	GE Power Systems Energy Consulting	NYISO	4.9	4.9	$0.00	Not applicable	–
Texas	Electric Reliability Council of Texas (ERCOT)	ERCOT-TOS-1A	5.2	5.2	$2.95	1638	138 and 345 kV
		ERCOT-TOS-1B	5.2	5.2	$3.78	1831	345 kV
		ERCOT-TOS-2	11.6	11.6	$4.93	2376	345 kV
		ERCOT-TOS-3	18.0	18.0	$6.38	3036	345 kV and HVDC
		ERCOT-TOS-4	17.5	17.5	$5.75	2489	345 kV and HVDC
	Southwest Power Pool (SPP)	SPP-2	4.5	4.5	$1.13	625	345 kV
	Southwest Power Pool (SPP)	SPP-1	1.5	1.5	$0.19	170	345 kV

Table 2 (*Continued*)

Region	Principal author	Study abbreviation	Incremental Wind Analyzed (GW)	Total incremental generation analyzed (GW)	Total transmission cost ($ Billion)	Length of new transmission (mi)	Primary voltage of new transmission lines (AC unless noted)
	Electric Reliability Council of Texas (ERCOT)	ERCOT-C3	3.0	3.0	$0.32	230	345 kV
		ERCOT-CW3	3.8	3.8	$0.96	862	345 kV
		ERCOT-M2	3.8	3.8	$0.86	650	345 kV
		ERCOT-P4	4.6	4.6	$1.52	770	345 kV
		ERCOT-Cb1	3.3	3.3	$0.86	–	345 kV
		ERCOT-Cb2	4.0	4.0	$1.16	–	345 kV
		ERCOT-Cb3	5.3	5.3	$0.94	–	345 kV
West	HPX Participants	HPX	3.3	3.8	$5.13	2560	500 kV
	K. R. Saline & Assoc. (for WestConnect)	EPTP-2	–	2.4	$1.50	987	500 and 230 kV
	K. R. Saline & Assoc. (for WestConnect)	SunZia	–	1.5	$0.80	350	500 kV
	SWAT Renewable Energy Task Force	SWAT	3.1	7.8	$1.67	–	500 and 230 kV
	Northwestern Energy Electric Transmission Planning	MSTI	–	1.5	$0.72	460	500 kV
	Arizona Public Service, PacifiCorp, National Grid, Wyoming Infrastructure Authority	TWE and GS	2.3	6.0	$5.97	2125	500 kV and HVDC
	Technical Analysis Committee (PG&E Chair)	C/PNW-NorCal	3.6	3.6	$5.00	950	500 kV and HVDC
	Western Regional Transmission Expansion Partnership (WRTEP)	Frontier-A	3.6	3.6	$4.30	1092	500 kV
		Frontier-B	2.6	3.6	$4.30	1092	500 kV
	Montana Alberta Tie Ltd. (MATL)	MATL		0.6	$0.12	216	230 kV
	Colorado Long Range Transmission Planning Group (CLRTPG)	CLRTPG-N1	0.7	3.6	$1.47	–	345 and 230 kV
	Northwest Transmission Assessment Committee (NTAC)	NTAC-1	3.2	4.0	$6.43	1849	500 kV (Submarine HVDC)
		NTAC-2A′	1.1	1.8	$0.86	600	230 kV
		NTAC-2A	1.1	2.2	$2.21	1269	500 and 230 kV
		NTAC-2B	1.1	2.3	$2.58	1255	500 (includes Submarine HVDC) and 230 kV
	Xcel Energy Transmission Planning	PSCo	0.8	0.8	$0.00	Not applicable	
	Tri-state Generation and Transmission and Western Area Power Administration	EPTP-1	–	1.8	$0.79	820	500 and 230 kV
	Clean and Diversified Energy Advisory Committee (CDEAC) Transmission Task Force	CDEAC	25.5	42.8	$6.79	3578	500 kV
	Northwestern Energy Electric Transmission Planning	Northwestern	–	1.5	$1.03	513	500 and 230 kV
	RMATS	RMATS-1	3.0	6.3	$0.97	971	345 kV
		RMATS-2	5.0	11.8	$4.27	3834	500 kV
	Seams Steering Group of the Western Interconnect (SSG-WI)	SSG-WI	18.5	34.3	$6.71	3360	500 kV

bottom-up transmission studies often include detailed physical modeling of the grid, and therefore will arguably produce more accurate estimates of the cost of transmission expansion if conducted appropriately. Recently, a number of bottom up transmission studies, ranging from very detailed to more conceptual, have included large amounts of new wind development. In comparison to a top-down model, these bottom-up studies examine specific transmission line paths and facility ratings. Detailed physical modeling of the transmission system, in the bottom-up studies that use it, also allows complex relationships between load, generation dispatch, power flows over parallel transmission paths, and reliability requirements to be incorporated into the analysis of transmission expansion requirements and costs.

In this article, based on selected results from a larger study by Mills et al. [26], we review a sample of 40 bottom-up transmission studies that have included wind power.[3] These studies cover a broad geographic area, and were completed from 2001 to 2008. Our primary goal in reviewing these studies is to develop a better understanding of the transmission costs needed to access growing quantities of wind generation (we do not address the institutional barriers to transmission investment). In so doing, we present information that allows a deeper appreciation of the nature and magnitude of the transmission cost barrier for wind energy. A secondary goal is to better understand differences in transmission planning approaches in order to identify those methodologies that seem most able to estimate the incremental transmission costs associated with wind development. Finally, in addition to providing some insight to policymakers and others on the magnitude of the transmission barrier and to transmission planners conducing bottom-up transmission assessments for wind, we hope that the resulting dataset and discussion might be used to inform the assumptions, methods, and results of top-down assessment models. In achieving all of these objectives, however, we are cognizant that the methodologies employed by the studies in our sample are diverse, and that comparisons among the studies are more illustrative than definitive.

The remainder of the article is structured as follows. We begin in Section 2 by identifying the transmission plans in our sample and highlighting differences among those studies. In Section 3, we discuss our methodology for estimating the unit cost of transmission for wind from each of the studies in our sample, the inherent assumptions in our simplified methodology, and the resulting caveats on the use and interpretation of our results. Section 4 presents pertinent statistics for each study in our sample, and the key results of our meta-analysis on the unit cost of transmission for wind across all studies. In Section 5 we compare the results of the bottom-up studies in our sample to pertinent results from a sample of relevant top-down models that include transmission estimates for wind. Conclusions are offered in Section 6.

[3] In so doing, we broadly follow the approach used by other studies in Europe. Auer et al. [27] and EWEA [28] summarized transmission cost studies from Europe, and concluded that the additional transmission expenditure for wind was likely to cost less than $6/MWh for up to 30% wind penetration. Wind transmission costs in the several European national case studies reviewed as part of IEA Task 25 range from 3 to 13% of the bus-bar cost of wind for up to 60% penetration on an energy basis for particular counties. The countries differ in how far from demand centers the future wind resources are located. There are also differences in national studies on how the costs are allocated to wind power – part of the reinforcements are usually made also for other reasons than wind power [29]. Additional work on the grid connection costs associated with renewable energy in Europe has been summarized in Swider et al. [30], focusing on just interconnection costs.

2. Description of transmission studies

2.1. Study sample

The 40 transmission studies included in our sample all analyze proposed transmission upgrades that are expected to accommodate increased wind power generation. In our collection of studies, we largely selected only those that evaluate transmission requirements for multiple new wind plants with a combined capacity greater than 300 MW; we therefore excluded from our sample individual generator interconnection studies. In a few cases, we included studies where wind resource maps and wind developer interest shows significant potential for new wind generation, even when those studies did not explicitly and separately evaluate wind.

The general location of the studies included in our sample is illustrated in Fig. 1, while the study region, author, title, date, and brief description of the scenarios from which we collect statistics are presented in Table 1 (more information on the content of the studies is presented in Table 2, later). The 40 studies in our sample cover a broad geographic area, were completed from 2001 to 2008,[4] and for those study-scenarios that specifically analyze wind power capacity, do so with wind additions that range from as little as 63 MW[5] to as much as 236 GW.

The remainder of this section explores the many variations among the studies in our sample, focusing on: the degree to which the study focuses on wind; the type of organization authoring the study and geographic scope of study; the framework for evaluating necessary transmission upgrades; the degree of network interconnectivity; and the level of study detail. In our description of these issues, we focus on those studies that are considerably different from one another; the majority of studies fall between extremes, and we do not attempt to categorize all studies along all dimensions.

2.2. Degree of focus on wind energy

A key distinguishing feature among the studies in our sample is the degree to which those studies focus on wind power in their analysis. On one extreme, a number of the studies were carried out with the express objective of determining the transmission investments and associated costs of accommodating increasing wind development. The Electric Reliability Council of Texas (ERCOT) and Southwest Power Pool (SPP) evaluations of competitive renewable energy zones (CREZs), for instance, estimated the cost of accommodating particular levels of incremental wind development in specific resource zones in Texas.

In contrast, a number of the studies in our sample include relatively small amounts of wind capacity compared to other forms of incremental generation capacity. As one example, the Midwest ISO (MISO) 2003 Transmission Expansion Plan based its assumed mix of incremental generation capacity on trends in the transmission interconnection queue at that time, and therefore included significant amounts of incremental gas and coal generation. Another particular aspect of this MISO study (as well as others) is that the various proposed transmission solutions were evaluated in the context of different projections for generation development, but the transmission evaluated in each scenario is by no means optimized for a particular amount of incremental wind development.

Finally, in a number of the studies covering the Western U.S., the focus is not so much on determining the specific

[4] No studies completed after December 2008 were included in our sample.

[5] The scenario with only 63 MW of wind is from one of the eight scenarios in the SCE transmission ranking cost report. The scenario with the next smallest amount of wind is 329 MW in the same SCE report.

transmission investments required to accommodating projected generation development, but instead on studying specific transmission lines that would add transfer capacity across otherwise-constrained paths. The Frontier, High Plains Express, Transwest Express and Gateway South, SunZia, Montana-Alberta Tie Line, Mountain States Transmission Intertie, and the Canada/Pacific Northwest-Northern California line studies are all examples of studies that focus primarily on particular transmission lines rather than on wind generation per se.[6]

2.3. Study authorship and geographic scope

Many of the larger regional studies in our sample were performed as part of the transmission planning process of Independent System Operators (ISOs) and Regional Transmission Organizations (RTOs). The Joint Coordinated System Plan (JCSP), a large regional transmission planning study covering the majority of the Eastern Interconnection, was performed by multiple ISOs and RTOs. A number of large regional transmission planning studies have also been conducted in the Western U.S. The SSG-WI and CDEAC studies, for example, cover the entire Western Interconnection. Outside of California, there are no ISOs or RTOs in the West, and in these instances large regional transmission planning studies have often been performed by state-led organizations or voluntary utility/transmission organizations. Finally, a number of studies in our sample were performed for state energy planning or regulatory bodies or regulated investor owned utilities (IOUs).

2.4. General framework: congestion vs. deliverability

Another important difference among the studies is the general framework used to evaluate transmission investments. These frameworks can be classified into two loose categories:

- Congestion focused[7]: transmission investments are made to economically reduce congestion (or system redispatch) costs that would be incurred with the addition of new generation.
- Deliverability focused: transmission investments are made to increase the transmission capacity between generators and load under particular system conditions.

Though individual studies sometimes fall between these two categories, the primary difference between the two approaches is that one focuses on decreasing congestion while the other focuses on increasing transmission transfer capacity. As an extreme example, consider an existing transmission line that is fully utilized by a remote fossil-fuel power plant that is $1/MWh cheaper than a local fossil-fuel plant. In the deliverability focused approach, a new wind generator located near the remote fossil-fuel plant will require new transmission infrastructure with a transfer capability equivalent to the nameplate capacity of the wind project. In contrast, the congestion focused approach will allow the output of the wind generator to displace the power of the remote fossil-fuel generator, and new transmission might not be built unless the cost of expanding the transmission system is lower than the savings gained by accessing cheaper, remote fossil resources ($1/MWh). As per this simple example, a deliverability focused approach can yield greater transmission expenditures than a congestion focused effort.

ERCOT performed an evaluation of several CREZs using a congestion focus. In the study they proposed transmission that would relieve binding constraints that would otherwise force wind to be curtailed to an unacceptable level (curtailment for greater than 2% of the year). The analysis involved a security constrained economic dispatch model of the entire system, using location-specific hourly wind data for existing and planned wind plants. The transmission solutions were evaluated in an iterative manner such that the least cost solutions were selected to reach the target level of wind development in a region.

In contrast, deliverability focused studies tend to center on developing lines that can increase the transfer capability between specific new generators (or areas) and specific load centers, without necessarily taking congestion costs (and therefore redispatch opportunities) into account. Planners using this framework will typically evaluate in great detail one or more transmission power flow cases that include both the new generation and proposed transmission during particular loading conditions (generally during a peak load case). The planner will then ensure that all constraints are met during normal system operation and during plausible contingences. The Technical Analysis Committee of the Canada/Pacific Northwest – Northern California Transmission Line Project, for example, performed an analysis of transmission options using a deliverability focus by focusing on post transient power flow contingency analysis during a heavy summer peak case.

The motivation for deliverability focused studies is often not to determine the least-cost transmission investments required to economically access a certain amount of new generation, but instead to document the transmission investments necessary to add new transfer capacity over a path that lacks available capacity. In this respect, in a deliverability focused study the transmission investments may be the same regardless of the type of generation that ultimately uses the new transmission facilities.[8]

In deliverability focused studies that specifically include wind capacity additions, study authors generally assume that those wind facilities require transmission transfer capacity equivalent to the name-plate rating of the wind projects (e.g., 3000 MW of new wind will require 3000 MW of new transmission capacity) or evaluate a limited number of snapshot powerflow cases in which all wind is assumed to be producing at its full nameplate capacity. A minority of studies, however, assume that it is possible to 'overbuild' wind generation by adding, for instance, 3600 MW of wind capacity and only 3000 MW of transfer capacity on a new transmission path. Though such a strategy may entail some curtailment of wind output, the cost of that curtailment may be lower than the cost of fully building transmission to meet peak wind conditions during peak transmission usage periods, and the magnitude of curtailment may be small if projects are geographically dispersed (due to the benefits of geographic diversity in wind production) [33]. A congestion focused study can inherently accommodate a similar strategy by allowing wind power to be dispatched down or

[6] Another way to phrase this issue is that some studies ask the question: what transmission improvements are required if we add new generation to the transmission system? Other studies, however, ask the question: how much transfer capacity will be added between regions if we build a particular transmission line?

[7] Congestion in this article is generally meant to refer to the increase in production costs that occurs when generators are dispatched out-of-merit order due to security constraints. Lesieutre and Eto [31] indicate that this definition of congestion cost is also commonly referred to as the system redispatch cost.

[8] Strbac et al. [32] present a detailed analysis of the difference in transmission costs for wind and conventional resources in the U.K. They find that it is not efficient to invest in transmission in order to be able to accommodate the simultaneous peak outputs from both conventional and wind generation. They also conclude that wind generation tends to drive less transmission investment than conventional generation, particularly when there are opportunities for the sharing of transmission assets between different generation technologies. Sharing transmission between different generating technologies enables economic redispatch opportunities when the transmission capacity is a binding limit or wind to utilize a portion of a transmission line that is unused by the other generation technologies while the wind is blowing.

curtailed if transmission limits are binding in a security constrained economic dispatch.

A final potential difference between a congestion focused study and a deliverability focused study is that authors of a deliverability focused study pick the load center to which the new generation will be delivered. Transmission solutions will then be evaluated to enable the specified transaction. A congestion study, however, need not specify the destination of a particular amount of new generation. Instead, a security constrained economic dispatch model will optimize the dispatch of all generation in a region subject to the constraint that all loads must be met, without specifying required transactions between particular generators and loads.

2.5. *Degree of transmission network interconnectivity*

A number of the studies in our sample evaluate transmission upgrades as part of a highly connected electrical network. The transmission element that is upgraded or replaced may allow some amount of additional flow over that element, but by relieving a binding constraint, may also allow significantly more power to flow over other, parallel paths. In these situations, the additional generation that can be accommodated behind a now relieved transmission constraint may be greater than the transmission capacity of the element added in the upgrade.

In contrast, many new proposed transmission lines in the West are between regions that have little existing transmission transfer capacity. The proposed lines may be connected at various points to the existing network, but resemble long radial lines rather than upgrades to specific network elements. These situations are typically modeled with a deliverability focus.

2.6. *Level of detail*

All of the studies are conceptual to some degree in that they require forecasts of future system conditions to estimate the loading of the transmission system and future generation development. The level of detail used in the evaluation of transmission and resources, however, varies considerably. Transmission projects that are very close to construction, such as the CAISO study of the Tehachapi expansion and the Xcel BRIGO study will incorporate power-flow, contingency, and stability analyses to evaluate transmission lines. This more-detailed approach is also used in a number of studies to evaluate large, but conceptual, transmission lines such as the C/PNW-NorCal study by PG&E. On the other hand, other studies of similar large, very conceptual transmission lines that resemble radial paths (e.g., the Frontier line study) often rely on less-detailed engineering judgment rather than on detailed electrical system modeling.

3. Methodology

Our comparison of the studies focuses primarily on the unit cost of transmission required to access wind resources. Here we describe our simple methodology for estimating this cost, and some of the limitations of that methodology. These limitations are due to the fact that the data available from many of the transmission planning studies in our sample do not allow for a direct estimation of the actual transmission cost attributable to increasing wind generation. To elucidate this point, we begin by briefly describing what data would be needed for a direct and accurate determination of the transmission costs imposed by increased wind power development.

3.1. *An "ideal" study*

Ideally, studies would provide the total cost of transmission that is due solely to the addition of a specified amount of wind generation, above and beyond any transmission expenditures required in the event that that wind generation did not exist and that other generation resources were used to meet load. In such an ideal study, the amount of congestion and the level of electricity reliability would also be equivalent between the two scenarios, allowing for a precise and fair comparison of transmission expenditures. In this instance, one could readily and accurately estimate the additional unit cost of transmission for wind by dividing the total cost of incremental transmission in the high wind scenario by the incremental amount of wind added in that scenario.

The transmission studies in our sample rarely meet these idealized requirements, in part because the purpose of these studies is not to uniquely estimate the incremental transmission costs associated with wind. In particular, with few exceptions, these studies do not estimate the cost of transmission that is exactly due to a particular amount of incremental generation added to the system, while keeping projected electricity reliability and congestion equal to what they would have been if the new generation and associated transmission were not added to the system. The Joint Coordinated System Plan (JCSP) in the Eastern Interconnection and the ERCOT CREZ analyses are rare examples of studies that come close to replicating an ideal study for determining the cost of transmission specifically for new wind. In many other studies, however, transmission is built to offset pending reliability concerns, relieve pre-existing congestion, or is sized so that other generation can be added to the network aside from just wind. In these instances, it is not possible to precisely estimate the incremental costs uniquely associated with new wind power additions.

3.2. *Simplified approach*

At the risk of over-simplification, but with the benefit of analytic simplicity, we largely ignore these complexities in our comparison of the studies (though we do come back to some of these issues in the subsequent discussion of our results). Our approach is to collect statistics on the aggregate cost of the proposed transmission upgrades evaluated in the study, as well as the nameplate capacity of incremental generator additions accessed by those transmission investments (as identified in the study itself). Where multiple scenarios are evaluated, we focus on those with higher levels of wind penetration. If readily and publicly available, we also collect information on the mileage and voltage of transmission lines added in the study, as well as the assumed cost per mile of different transmission configurations. The transmission plans in our sample often do not clearly state all of the various statistics sought for the present article, however, requiring in many instances a degree of judgment to gather relevant statistics. The exact values presented in this article should therefore be taken with all due caution.

To loosely compare the studies based on the estimated unit cost of transmission for wind while also ignoring the many complexities associated with such simple comparisons, we use two units, one based on the nameplate rating of wind generation ($/kW-wind) and the other based on projected wind-generated electricity ($/MWh-wind). In those transmission studies in which wind is the only incremental generation added, we calculate the unit cost of transmission for wind in $/kW-wind terms by simply dividing the aggregate cost of the proposed transmission upgrades evaluated by the study by the nameplate capacity of the incremental wind. We then calculate the unit cost in $/MWh-wind terms by levelizing the transmission cost and dividing that figure by the amount of annual energy production expected from the new wind additions. For this article, the levelizing factor was assumed to be a constant 15% per

year for all transmission lines and the capacity factor of wind was assumed to be 35% for all wind plants. The dollar value varies widely across studies. Many studies do not clearly state whether the results are in nominal or constant dollars and if in constant dollars, for which year. As such, for this study we simply assume that all cost figures are reported in nominal, non-discounted dollars and report the data as provided by the study authors. Further discussion of these assumptions is available in the full report.

These metrics are more difficult to calculate when a transmission study evaluates not just wind additions, but the addition of multiple generation types (e.g., wind, solar, gas, and coal). In these cases, it is typically impossible to specifically isolate the transmission costs uniquely associated with wind. Instead, we must simply assign a share of the additional transmission costs to all of the incremental generation. We do so based on a capacity weighting. On a capacity-weighted basis, the unit cost of transmission for wind in $/kW-wind terms is estimated by simply dividing the total transmission cost in a study by the total amount of incremental generation capacity (wind and non-wind) modeled in that study. In so doing, this metric assumes that within any individual study all incremental generation capacity imposes transmission costs in proportion to its nameplate capacity rating. Capacity weighting also reflects the fact that firm reservations on transmission lines are typically based on capacity, and that a new power plant will often reserve its full nameplate capacity on a transmission path over which it plans to move power. We calculate the capacity-weighted unit cost of transmission for wind in $/MWh-wind terms in the same way as described previously.

Because our methodology, and the studies themselves, differ from the ideal scenario described earlier, our estimates of the unit cost of transmission for wind are imprecise, and comparability among studies is imperfect. In addition those limitations mentioned earlier, there are four additional important limitations that are discussed in detail in the next section.[9] These four are that our methodology implicitly assumes that (1) new generation shares responsibility for the new transmission lines, (2) incremental generation is the only beneficiary of new transmission, (3) transmission is sized exactly to accommodate the generation added in the scenario, and (4) the reference future requires no new transmission.

Because of these limitations our methodology best captures the additional cost of transmission attributable to wind when faced with radial lines to remote regions to access generation resources that are co-located. Our methodology is not as well suited to cases where new transmission is part of a well connected network that provides congestion relief, reliability benefits, and access to a wide variety of resources, not all of which require new transmission. The results of our analysis should therefore be interpreted and used with care. Despite the important limitations noted here, however, we do believe that the overall comparisons made in this article can improve our understanding of the range of transmission costs needed to access greater quantities of wind, and to highlight some of the drivers of those costs.

4. Results

4.1. Overview

Key data collected from each of the 40 transmission planning studies, and where appropriate their multiple study scenarios, are summarized in Table 2. In particular, the amount of incremental wind power capacity (and total capacity) analyzed in the study is listed, along with the total cost of the associated transmission upgrades. A few studies do not specify what fraction of aggregate generation additions come from wind; these are indicated by blank cells in the "Incremental Wind Analyzed" column. The table also lists the primary voltages and total length of new transmission investments built in the specific study scenario, where those data are available.

4.2. Implied unit cost of transmission for wind

Using the data presented in Table 2, the implied unit cost of transmission for wind can be calculated as described in earlier in Section 3. The resulting unit cost of transmission for wind, in $/kW-wind and $/MWh-wind terms, for our sample of studies is shown in Fig. 2, sorted by increasing unit costs.[10] The total amount of incremental wind capacity analyzed by each study scenario ("wind analyzed"), or the total incremental capacity in cases when it is not clear what portion of the new capacity is wind ("total analyzed"), is illustrated on the top axis of the figure.

Though the limitations of our approach to calculating these costs should not be ignored, it is evident that the total range in unit transmission costs for wind implicit in these studies is vast – ranging from $0/kW to over $1500/kW, based on our methodology. The majority of studies, however, have a unit cost of transmission that is below $500/kW, or roughly 25% of the current $2000/kW cost of building a new wind project. The median unit cost of transmission for wind (capacity-weighted) from all scenarios in our sample is $300/kW, roughly 15% of the current cost of building a new wind project.[11]

As shown in Fig. 2, the unit cost of transmission for wind in $/MWh terms is below $25/MWh in the majority of study scenarios. The median cost of transmission (capacity-weighted) from all scenarios is $15/MWh. These figures compare to recent busbar wind power prices that range from $35/MWh to as high as $65/MWh with an average of $45/MWh [34].[12] As such, the median unit cost of transmission, as estimated here, represents a cost adder of roughly 33% to the busbar price of wind, in most instances. The overall range in the unit transmission cost of wind is again vast, however, with a range of $0/MWh to as high as $79/MWh.

4.3. Effect of methodological limitations

Our estimates of the cost of transmission for wind, based on our sample, are complicated by the limitations of our methodology. These limitations ensure that, for any individual study, our estimate of the implied unit cost of transmission for wind may be either biased upwards or downwards. Here we provide specific examples of how these limitations might impact our results, and suggest that these limitations as a whole likely lead us to overstate the unit cost of transmission for wind.

4.3.1. Shared responsibility for new transmission lines

If a study adds, for example, new coal plants and new wind plants that are co-located, meaning that the same transmission

[9] Again, our study does not address the issue of cost *allocation*, and the unit cost of transmission for wind reported in this study does not imply that new wind generation projects will actually be responsible for paying these full costs.

[10] The MISO'06 study is not included in this or later graphics nor in the calculation of the median unit cost, for reasons discussed later in this section.

[11] In the early 2000s, the average cost of wind projects was roughly $1300/kW. Using this average wind project cost for the denominator, the $300/kW median unit cost of transmission cost equates to 23% of the average wind project cost.

[12] The wind power price is the capacity-weighted average sale price for wind projects built in 2007. Prices include the production tax credit (PTC). If the federal PTC was not available the range would increase to between approximately $50/MWh and $85/MWh with an average of roughly $65/MWh. If the average wind price without the PTC were used in the denominator, then the median transmission cost would be approximately 23% of the average wind price.

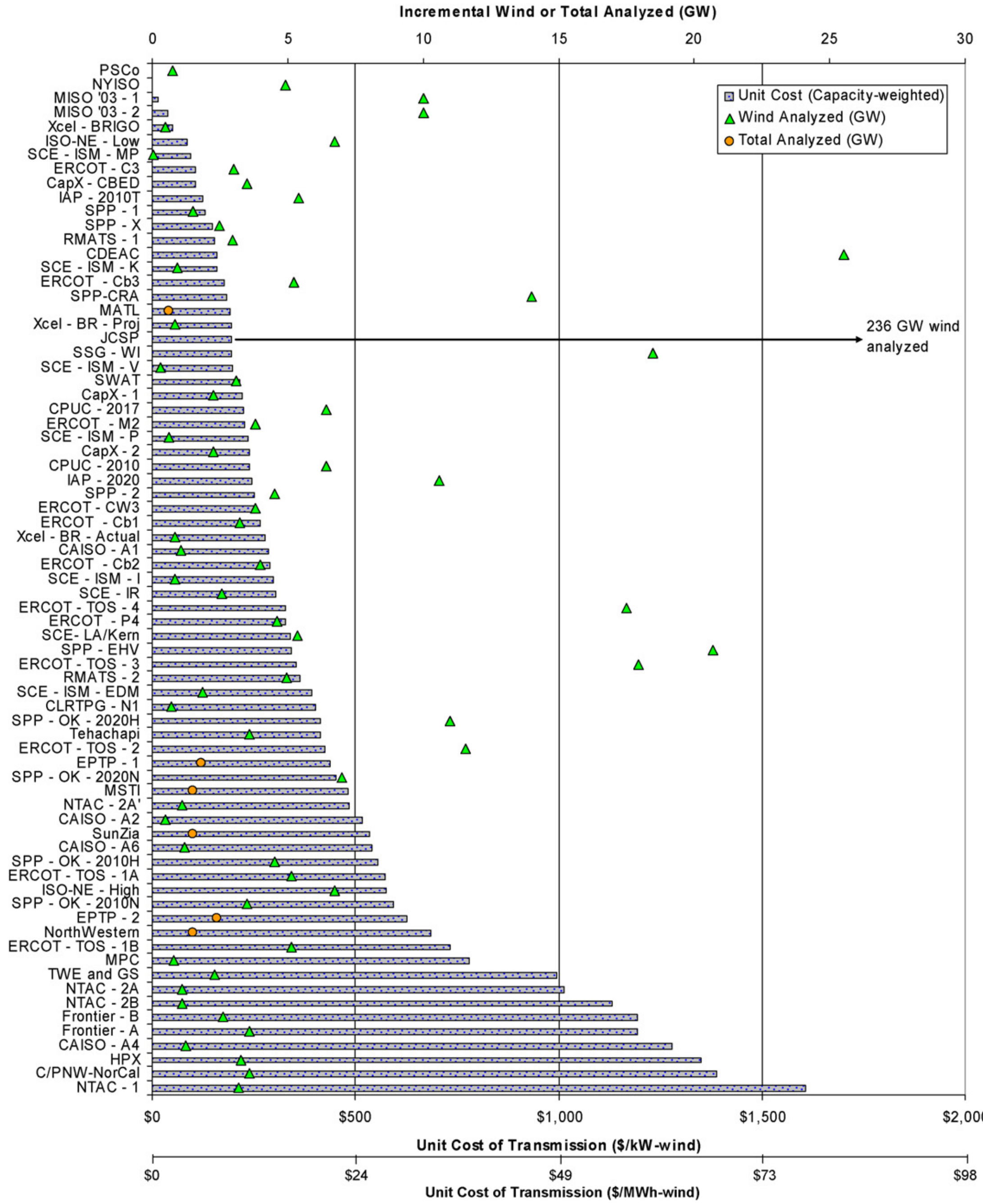


Fig. 2. Unit cost of transmission for wind in \$/kW-wind and \$/MWh-wind terms (*note*: (1) unit cost of transmission in nominal dollars from various years, (2) transmission cost in \$/MWh-wind terms is levelized using 15% per year, levelizing factor, (3) unit cost in \$/MWh-wind terms assuming wind plants have 35% capacity factor for all scenarios).

facilities can be used by both generator types, our methodology should provide an upper bound for the cost that is attributable to wind. On the other hand, if a transmission study adds wind in remote areas and new gas plants near load centers, but does not separate the responsibility for transmission investments between wind and gas, then our methodology will incorrectly assume that both generator types are equally responsible for the incremental transmission costs. In so doing, we will understate the cost of transmission attributable to wind.

In the full report we identify seven scenarios for which this particular limitation in the methodology may understate the cost attributable to wind. In the extreme, if one assumes that new natural gas plants in these 7 scenarios impose no added transmission costs, but that all other resource types (e.g., wind, coal, and small hydro) are equally responsible on a capacity-weighted basis, then the implied unit cost of transmission for wind would increase for these 7 scenarios as indicated in Table 3. As shown, with this extreme assumption, the implied unit cost of transmission for wind in a given scenario increases by 22–265%. The median unit cost of transmission for wind across all studies, previously reported at \$300/kW, increases to \$330/kW if one uses the revised figures for the seven scenarios shown in Table 3. Based on these calculations, at least, it seems that this particular limitation to our methodology has little effect on the overall results presented here, though it does impact the results of several individual scenarios.

Table 3
Impact of assumption of shared responsibility on the unit cost of transmission.

Scenario	Unit cost of transmission ($/kW, capacity-weighted)		
	Assuming shared responsibility	Assuming no responsibility for natural gas plants	Potential percent increase in unit transmission cost
MISO'03-1	$14	$50	265%
MISO'03-2	$39	$143	265%
SSG-WI	$196	$271	38%
CapX-1	$222	$430	93%
CapX-2	$238	$460	93%
NTAC-2A	$1014	$1242	22%
NTAC-2B	$1132	$1449	28%
Median across all studies	$300	$330	10%

4.3.2. *Incremental generation as only beneficiary of new transmission*

Our methodology assigns all additional transmission costs to new electricity generators, and thereby effectively assumes that the only beneficiaries of the new transmission investments are those generators. In reality, however, studies frequently point to the additional reliability benefits and congestion relief that new transmission will provide. In these cases, our methodology overstates the transmission costs that are attributable specifically to wind.

As one example, in the Tehachapi study, the total cost of transmission to connect 4.4 GW of incremental generation was estimated at $1.8 billion. Our methodology implicitly assumes that this cost is solely attributable to the new incremental generation. The study, however, indicates that the transmission upgrades will allow the deferment of otherwise planned reliability upgrades, leading to a clear overstatement of the unit cost of transmission for wind using our methods.

4.3.3. *Transmission exactly sized to meet generation additions*

Another implicit assumption in our methodology is that new transmission is sized to exactly the size required by the incremental generation added in a particular scenario. In reality, this is not always the case. Lumpiness and economies of scale in transmission investments suggest that it is better to oversize lines than to try to size them exactly for forecasted needs [19]. A number of studies appear to present scenarios in which transmission capacity exceeds what is necessary to accommodate the new generation contemplated by the study's authors. In one of the ERCOT scenarios (ERCOT-TOS-1B), for example, the proposed transmission is designed so that it can not only accommodate the specified amount of wind additions, but also so that the system can be further expanded in the future to accommodate more wind at less cost than might otherwise be the case.

A more extreme example of transmission not being sized to the amount of incremental generation additions is a study called the "Vision Exploratory Study" that was part of the MISO transmission expansion plan for 2006. In that assessment, a 765 kV network overlay between the Dakotas and the Eastern Seaboard was proposed along with 16 GW of incremental wind capacity. Further analysis of the details behind this study, however, revealed that the transmission proposed in the scenario was substantially oversized for the amount of added generation. As a result, this scenario is excluded from the graphics presented earlier and the calculation of the median unit cost of transmission. We discuss the approach and results of the study in the full report.

Among our study sample as a whole, it is not entirely clear how sizable an effect the mismatch of transmission size and incremental generation might have. Nonetheless, by assigning the full cost of new transmission to the new generators specified by such studies, our methodology will tend to overstate the unit cost of transmission uniquely attributable to wind.

4.3.4. *Reference future requires no transmission*

Our methodology also effectively assumes that the transmission investments analyzed by each study do not displace transmission that would need to be built in a reference future without the new wind. In reality, some additional transmission expansion is likely to be needed to accommodate load growth and the addition of other (non-wind) electricity generators.

We present the results from the SSG-WI high renewables scenario, for example, but SSG-WI also evaluated transmission needs in a scenario in which projected load growth is met primarily with gas and in another scenario with increased coal additions. The study found that new transmission would be needed in all three scenarios. In fact, the study found that the high coal scenario required the most transmission investment.

By assuming that these costs are not "avoidable" by the specified wind additions, and by instead attributing the full cost of new transmission in the SSG-WI high renewable scenario to the new generation in that scenario, we overstate the incremental social cost of transmission attributable to wind. In fact, because this limitation is prevalent among the studies in our sample, the estimates for the unit cost of transmission for wind summarized here should not be considered incremental costs, considered in isolation. Instead, they would ideally be compared to similar estimates for the unit cost of transmission association with other generation technologies.

5. Comparison to top-down transmission cost estimates

Though the studies in our sample use different methodologies and varying levels of detail, they all provide a bottom-up approach to transmission planning on a regional basis, based on the specific characteristics and modeling of the electric power grid. In contrast, certain top-down studies are often conducted on a national basis, and are unable to incorporate detailed physical modeling of the transmission system. Such studies must use cruder approaches to estimating the transmission requirements associated with wind deployment.

In this section, we specifically compare the implied unit cost of transmission across the detailed, bottom-up studies in our sample to the results of three, more-conceptual top-down studies. Two of these top-down studies were conducted in the context of the U.S. DOE's analysis of the technical and economic feasibility of achieving 20% wind electricity penetration in the U.S. The third top-down approach considered here is the EIA's National Energy Modeling System (NEMS), which is used (among other things) to produce the EIA's Annual Energy Outlook.

As shown in the text that follows, the unit cost of transmission in two of the three top-down studies broadly agree with the mid- to lower-end of the range from the bottom-up studies. The unit cost implied in the third top-down study is 50% greater than the median cost of the studies in our sample. As discussed earlier, the bottom-up estimates likely overstate actual transmission

expenditures for wind, perhaps further reinforcing the results of the two lower cost top-down studies. The top-down studies often evaluate much higher levels of wind penetration than assumed in the bottom-up studies, however, making comparisons somewhat inappropriate.[13] Therefore, perhaps the most that can be concluded is that the top-down studies discussed below do not generate results that are wildly out of line with the more-detailed bottom-up assessments summarized in this article.

5.1. 20% wind energy: AEP 765 kV overlay

American Electric Power (AEP) developed a conceptual design for a 765 kV transmission network overlay across the U.S. that could facilitate the wind power additions needed to achieve 20% wind electricity by 2030 [35], as specified in the U.S. DOE's 20% wind energy analysis [3]. AEP owns and operates 765 kV lines in the Eastern U.S.

The 765 kV network overlay was developed by connecting 765 kV lines between load centers and areas of high wind potential, using (wherever possible) routes identified in previous regional transmission proposals. Fifty-five wind connection points were identified in the network. The amount of wind installed at each wind connection point was assumed to be equivalent to the transfer capacity of a single 765 kV line. The 765 kV network was designed so that each wind connection point is connected to the 765 kV network overlay through at least two 765 kV lines. The network is therefore designed so that the system would remain within operating limits during contingencies. As specified by AEP, the proposed network included 19,000 miles of 765 kV line and could accommodate 200–400 GW of wind capacity. The cost of the transmission system was estimated to be $60 billion.

The AEP proposal was meant for discussion purposes, and did not involve detailed modeling of the electric power system. AEP's engineering judgment, however, does hold some authority due to the company's experience with developing and building 765 kV lines. Based on our simplified methodology, the unit cost of transmission implied by the AEP 765 kV Overlay is $150–$300/kW-wind. The low estimate of the unit cost of transmission is 50% of the median value among the studies in our sample ($300/kW-wind) and the high estimate is nearly equivalent to the median value in our sample.

5.2. 20% wind energy: wind deployment system (WinDS)

The National Renewable Energy Laboratory used the Wind Deployment System (WinDS) model to evaluate a scenario in which wind provides 20% of the nation's energy by 2030, requiring more than 290 GW of additional wind capacity. AEP, as discussed above, provided a companion proposal for the same 20% wind scenario.

Though WinDS does incorporate a detailed geographic representation of the transmission system and addresses NERC reliability requirements through model constraints, it is based on a transport model rather than a powerflow model. The WinDS model, as employed in U.S. DOE [3], simply assumed that 10% of existing transmission capacity was available for wind energy. As wind deployment increases beyond this 10% limit on existing lines, the model adds new transmission capacity. As a result, for the 20% scenario, WinDS predicts that 71 GW of new wind will use pre-existing transmission capacity, and that the remainder requires some incremental transmission capacity.[14] The cost for the new transmission is estimated to be $60.8 billion.

Based on our simplified methodology, the unit cost of transmission implied by this study is $207/kW-wind [3]. Clearly, the transmission cost estimates from the WinDS model suggest that vast quantities of wind can be developed in the U.S. without requiring extremely high unit costs of transmission. The $207/kW-wind figure is 69% of the median value among the studies in our sample ($300/kW-wind), is below the implied unit cost of transmission for 70% of the study scenarios in our sample, and is consistent with the JCSP study and many of the studies that evaluate greater than 10 GW of new generation additions.

5.3. NEMS long-term (LT) multipliers

The National Energy Modeling System (NEMS) is used by the EIA in its Annual Energy Outlook (AEO), as well as to prepare topical reports for the U.S. Congress and others. The treatment of wind in general, and transmission in particular, has changed somewhat over time. Currently, the transmission cost for wind has been incorporated as a base transmission cost, which is consistent among all generation capacity and includes transmission costs related to load growth, and a wind-specific capital cost multiplier.

In particular, the average base transmission cost adder that is applied to wind capacity by NEMS is $316/kW.[15] In addition to this base transmission cost adder the cost of wind is assumed to further increase as wind is added in a region, due to a variety of factors, including resource degradation, increasingly challenging terrain for developing projects, and additional transmission upgrades above the base transmission cost. The long-term capital cost multiplier in NEMS ranges from one to three times the overnight capital cost of wind additions. For AEO 2008, for example, these multipliers add an additional cost of approximately $0–$3370/kW[16] to wind, depending on the level of wind deployment in a region [36]. The multiplier that applies to each level of deployment in a region (the "step size" of the multipliers) is largely based on analysis from the NREL WinDS model, however several adjustments were applied to the WinDS output to generate the multiplier step sizes actually used in NEMS [37].

Because the level of the EIA NEMS multiplier has such a large range, and because the multiplier intends to address multiple issues, of which transmission is only one, it is very difficult to compare the NEMS results with those in our transmission study sample. Nonetheless, the amount of potential wind capacity impacted by these multipliers, by region, is presented in Fig. 3. The figure also shows the amount of regional wind capacity added by 2030 from the AEO 2008 reference case, and therefore depicts the degree to

[13] As described earlier, however, the unit cost of transmission for wind is unlikely to increase as dramatically as one might initially expect as deployment increases. Additionally, the bottom-up studies, because they are conducted on a regional basis, imply a greater national penetration of wind than might otherwise be expected. As a result, it is not entirely inappropriate to compare the bottom-up, regional transmission plans in our sample to top-down studies that evaluate high levels of national wind power deployment. The JCSP study and many of the studies that add more than 10 GW of new generation are particularly appropriate for comparison and the implied unit costs of transmission in these scenarios are relatively close to the three top-down studies.

[14] This assumption may be a bit aggressive based on indications that new transmission must be built in many regions to accommodate a substantial increase in wind energy. Two studies in our sample (NYISO and PSCo) did, however, show that a certain amount of new wind generation can be added to the grid before transmission would need to be upgraded. Most studies did not have the objective of answering the question of how much new wind can be added to the system before transmission upgrades will be required. We therefore cannot use the results from our sample to directly evaluate the merits of this assumption in U.S. DOE [3].

[15] The base transmission cost adder varies by region from $220 to $580/kW ($2006). For wind deployed in 2030 in AEO 2008 the average wind base transmission cost was $316/kW.

[16] The high-cost adder corresponds to the 3× long-term multiplier of the capital cost, which in the Annual Energy Outlook 2008 was assumed to be $1,683/kW ($2006) for 2030 [38].

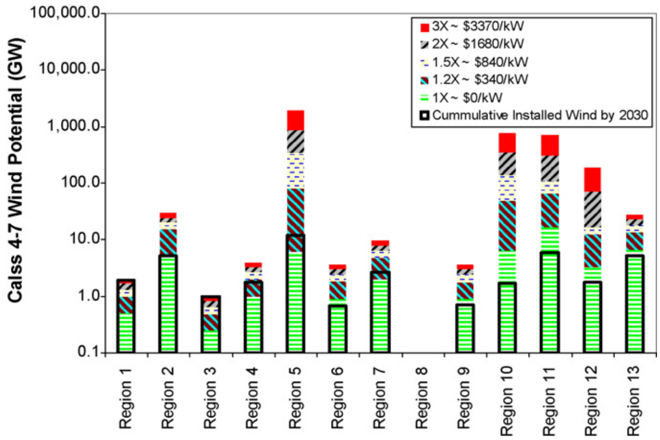


Fig. 3. NEMS long-term multiplier step sizes and cumulative amount of wind developed in each region by 2030, for AEO 2008 reference case (regions are defined as follows: East Central Area Reliability Coordination Agreement – 01; Electric Reliability Council of Texas – 02; Mid-Atlantic Area Council – 03; Mid-America Interconnected Network – 04; Mid-Continent Area Power Pool – 05; Northeast Power Coordinating Council/New York – 06; Northeast Power Coordinating Council/New England – 07; Florida Reliability Coordinating Council – 08; Southeastern Electric Reliability Council – 09; Southwest Power Pool – 10; Western Electricity Coordinating Council/Northwest Power Pool Area – 11; Western Electricity Coordinating Council/Rocky Mountain Power Area and Arizona-New Mexico-Southern Nevada Power Area – 12; Western Electricity Coordinating Council/California – 13).

which these estimated capacity additions are affected by the EIA's cost multipliers.

In aggregate, AEO 2008 forecasts 40 GW of new wind capacity by 2030. On average, the multiplier for these wind additions was 1.08×, roughly an additional $132/kW-wind. Recognizing that the NEMS multiplier is meant to reflect more than just transmission costs, adding the base transmission cost and the long-term multipliers for wind in 2030 leads to a total cost adder of $450/kW or 50% greater than the median unit cost in our sample ($300/kW).

On a regional basis, the realized NEMS multipliers vary considerably. Regions 1 and 3 (East Central Area and Mid-Atlantic Area), for example, both reach the highest 3× multiplier by 2030, adding $3370/kW to the capital and base transmission cost of incremental wind capacity in those regions. The transmission studies in our sample do not support multipliers at this level, but again, the EIA multipliers intend to capture effects other than transmission. The remaining regions reach only the 1.2× multiplier (around $340/kW additional cost) or remain in the 1× multiplier step (no additional beyond the base transmission cost) by 2030 in AEO 2008. Many of the bottom-up transmission studies in our sample, as well as the AEP and WinDS results, have an implied unit cost of transmission that is similar to the cost represented by the base transmission cost adder in NEMS ($300/kW median for our sample versus a $316 base transmission cost for wind in NEMS).

6. Conclusions

Recent growth in wind power development in the United States has been coupled with a growing concern that this development will require substantial additions to the nation's transmission infrastructure. It is clear that institutional issues related to transmission planning, siting, and cost allocation will pose major obstacles to accelerated wind power deployment, but also of concern is the potential cost of this transmission infrastructure build out.

In this article, we have reviewed a sample of 40 regional transmission studies that have included wind power. These studies vary considerably in scope, authorship, objectives, and methodology, making comparisons difficult. Regardless, our analysis of these studies reveals considerable differences in the implied unit cost of transmission for wind. In particular, the total range in unit transmission costs for wind implicit in these studies is from $0/kW to over $1500/kW, though some of this range is surely the result of flaws in our methodological approach.

The majority of studies in our sample, however, have a unit cost of transmission that is below $500/kW, or roughly 25% of the current $2000/kW capital cost of building a wind project. The median cost of transmission across all scenarios in our sample is $300/kW, on a capacity-weighted basis; roughly 15% of the current cost of building a wind project or 23% of the cost of building a wind project in the early 2000s. In terms of cost per megawatt-hour of wind power generation, the median cost is $15/MWh on a capacity-weighted basis, and most studies fall below $25/MWh. Two highly conceptual, top-down studies of 20% wind power penetration in the U.S. electricity system have implied unit costs of transmission below or nearly equivalent to the median cost of our sample of 40 bottom up transmission planning studies.

These mid-range costs, though not insignificant, are also not overwhelming. Additionally, the limitations of our methodology likely err towards an over-statement of the unit cost of transmission for wind. The need for transmission expansion, for example, is not unique to wind: other generation sources will also require transmission expenditures. Transmission expansion also typically serves multiple purposes, and our approach to assigning the full costs of that expansion to generation capacity additions effectively ignores those other benefits. And, in at least some of the studies in our sample, transmission is oversized, leading to an over-estimate of the transmission costs uniquely associated with wind additions. Finally, in taking a deliverability (rather than congestion) focus, a number of the studies in our sample reflect existing contractual limits that, if overcome, could increase the efficiency of grid operations and lower the unit cost of transmission for wind; further work on this specific issue is merited.

Because the range of transmission costs surveyed here is broad, however, with a number of high-cost scenarios, it is also important to understand how differences in study objectives, methodologies, and assumptions can impact the resulting cost estimates. Our work has only begun that process, and far more comparative work is needed. We find little evidence that higher levels of wind penetration require dramatically increased unit transmission costs, relative to more-moderate levels of wind deployment. This seems to be confirmed by two top down scenarios of 20% wind energy in the U.S., the JCSP study of 20% wind energy in the Eastern Interconnection, and by a number of bottom up study scenarios that add greater than 10 GW of new generation. It therefore appears that the unit cost of transmission for wind need not increase dramatically at higher levels of wind penetration.

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Appendix A. Transmission reports

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